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STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-03-0437

IN THE MATTER OF THE ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT

DIRECT TESTIMONY OF DR. DENNIS W. GOINS ON BEHALF OF THE FEDERAL EXECUTIVE AGENCIES

Arizona Corporation Commission
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February 3, 2004

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INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dennis W. Goins. I operate Potomac Management Group, an economics and management consulting firm. My business address is 5801 Westchester Street, Alexandria, Virginia 22310.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Ph.D. degree in economics and a Master of Economics degree from North Carolina State University. I also earned a B.A. degree with honors in economics from Wake Forest University. From 1974 through 1977 I worked as a staff economist at the North Carolina Utilities Commission. During my tenure at the Commission, I testified in numerous cases involving electric, gas, and telephone utilities on such issues as cost of service, rate design, intercorporate transactions, and load forecasting. While at the Commission, I also served as a member of the Ratemaking Task Force in the national Electric Utility Rate Design Study sponsored by the Electric Power Research Institute (EPRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Since 1978 I have worked as an economic and management consultant to firms and organizations in the private and public sectors. My assignments focus primarily on market structure, planning, pricing, and policy issues involving firms that operate in energy markets. For example, I have conducted detailed analyses of product pricing, cost of service, rate design, and interutility planning, operations, and pricing; prepared analyses related to utility mergers, transmission access and pricing, and the emergence of competitive markets; evaluated and developed regulatory incentive mechanisms applicable to utility operations; and assisted clients in analyzing and negotiating interchange agreements and power and fuel supply contracts. I have also assisted clients on electric power market restructuring issues in Arkansas, New Jersey, New York, South Carolina, Texas, and Virginia.

I have submitted testimony and affidavits in more than 100 proceedings before state and federal agencies as an expert in cost of service, rate design, utility planning and operating practices, regulatory policy, and competitive market issues. These agencies include the Federal Energy Regulatory Commission (FERC), the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, and regulatory agencies in Arkansas, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. Details of my professional qualifications are presented in Appendix A.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Federal Executive Agencies (FEA), which is comprised of all Federal facilities served by Arizona Public Service Company

(APS). Two of the larger FEA facilities are Luke Air Force Base and the Marine Corps Air Station in Yuma, both of which APS serves under Rate Schedule E-34 Extra Large General Service.

Q. WHAT ASSIGNMENT WERE YOU GIVEN WHEN YOU WERE RETAINED?

A. I was asked to undertake two primary tasks:

1. Review APS' proposed cost-of-service analyses (including pro forma adjustments) and related rates.
2. Identify any major deficiencies in the cost analyses and proposed rates and suggest recommended changes.

Q. WHAT SPECIFIC INFORMATION DID YOU REVIEW IN CONDUCTING YOUR EVALUATION?

A. I reviewed APS' application, testimony, exhibits, and responses to requests for information. I also reviewed information found on web sites operated by the Commission, and by APS and its parent company, PinnacleWest.

CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. On the basis of my review and evaluation, I have concluded the following:

1. Cost-of-Service. APS has proposed increasing base revenues by approximately $175 million (9.77 percent), which reflects a $167-million increase (9.31 percent) in base rates and APS' proposed $8-million Competition Rules Compliance Charge (CRCC). In developing proposed rates for its retail electric services, APS first conducted a cost-of-service study for the test year ending December 31, 2002. In this cost analysis, APS allocated and/or directly assigned its costs to functional segments of

its retail electric business. The return component of APS' costs reflects a requested 8.67 percent return on its retail jurisdictional rate base.

In allocating demand-related production and transmission costs to major customer classes, APS used the average of monthly system coincident peaks for June-September in the test year—a 4CP methodology. APS allocated costs related to distribution substations and primary distribution lines on the basis of noncoincident peak (NCP) demands. In contrast, APS allocated costs related to distribution transformers and secondary distribution lines on the basis of the sum of individual peak demands within a specific customer class.

2. Revenue Spread. APS spread its proposed revenue increase among rate classes on an equal-percentage, across-the-board basis. Under APS' revenue spread, each class received a 9.31 percent increase in base rates (excluding the CRCC). By choosing the across-the-board spread, APS' proposed rates barely move any customer class closer to cost of service.

As a result of its proposed revenue spread, APS increased the level of interclass revenue subsidies by about 15 percent—from around $80 million under present rates to more than $92 million under proposed rates. Approximately $87 million of the interclass subsidies created under APS' proposed revenue spread goes to Residential customers. That is, test-year revenues from APS' proposed Residential rates are about $87 million less than APS' costs (as determined in its cost-of-service study) of serving this class. APS makes up this shortfall—as well as the $5.5 million in subsidies received by Irrigation and Lighting customers—by overcharging General Service customers. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than APS has proposed.

3. Rates E-34 and E-35. With respect to the two rates under which it serves most Extra Large General Service customers (those with average monthly demands equal to or exceeding 3 MW), APS has:

- Unbundled the rates to provide both a Bundled Standard Offer Service applicable to customers who continue to purchase their full retail electricity requirements from APS, as well as unbundled pricing components applicable to Direct Access customers.
- Overcharged these customers by up to \$13.6 million. That is, proposed Rates E-34 and E-35 produce test-year electric sales revenues that exceed APS' cost of serving these customers by up to \$13.6 million.
- Introduced voltage discounts into the rates—\$0.69 per kW for Primary voltage customers and \$4.18 per kW for customers served at transmission voltages (that is, 69 kV and higher).
- Added May to the current June-October summer billing months used to determine 80-percent ratchet billing demands. Such ratchet demands become the customer's monthly billing kW[1] if they exceed the customer's highest 15-minute demand in the current month.
- Added two hours to the daily on-peak period in Rate E-35—moving from 11 a.m. – 9 p.m. Monday-Friday under the current rate to 9 a.m. – 9 p.m. under APS' proposed Rate E-35.

RECOMMENDATIONS

Q. WHAT DO YOU RECOMMEND ON THE BASIS OF THESE CONCLUSIONS?

A. I recommend that the Commission:

1. Approve APS' average 4CP methodology to allocate demand-related production and transmission costs. This methodology reflects the

principal factors—coincident summer peak demands—driving the need for generation and transmission capacity on the APS system. Allocation methods that dilute the impact of APS' summer peak demands (for example, a 12CP methodology that reflects APS' test-year monthly peak demands) ignore the dominant summer peaking characteristics of the APS system and result in understating the cost responsibility of classes with relatively low load factors and high summer peak demands.

2. Reject APS' proposed revenue spread. As I noted earlier, under APS' proposal, General Service customers pay approximately $92 million in interclass revenue subsidies to Residential, Irrigation, and Lighting customers. The Commission should require APS to spread the allowed revenue increase such that classes currently being subsidized will get 150 percent of the average system rate increase (excluding the CRCC). For example, if APS received its requested 9.31 percent increase in base revenues, the Residential, Irrigation, and two Lighting classes would get 13.97 percent increases. General Service customers would get whatever increase is necessary to achieve the overall system average 9.31 percent increase. Spreading APS' revenue increase in this manner would move each class significantly closer to cost of service, and also create meaningful reductions in interclass revenue subsidies. Details of how to implement this revenue spread approach are presented later in my testimony.

3. Reject APS' proposed Rates 34 and 35. Instead, the Commission should approve my recommended Rates 34 and 35, which reflect major changes to APS' proposed rates. These changes include:

- Reducing the proposed Transmission voltage discount from $4.18 per kW to $3.30 per kW, and increasing APS' proposed Primary voltage discount from $0.69 per kW to $1.40 per kW. These changes are

[1] On-peak billing kW in Rate E-35.

necessary not only to make the discounts more cost based, but also to reduce the likelihood that transmission voltage customers using Rates 34 and 35 receive rate decreases as they do under APS' rate design.

- Increasing the peak and off-peak energy charge differential in Rate E-35 to encourage more efficient electricity usage.
- Maintaining not only the current summer billing months (June-October) used to determine 80 percent ratchet billing demands in both rates, but also the 11 a.m. – 9 p.m. Monday-Friday on-peak period in Rate E-35. I make this recommendation because APS has not justified extending either the summer billing months or the daily on-peak period. Moreover, I do not believe that APS' proposed rates reflect the potential revenue impacts of lengthening these periods—that is, reflect the incremental revenue increase that it would likely receive if these periods were lengthened.

COST OF SERVICE

Q. HOW DID APS ALLOCATE ITS COSTS TO CUSTOMER CLASSES?

A. APS conducted a detailed cost-of-service study using data (adjusted in many cases) for the test year ending March 31, 2002. In this cost analysis, APS allocated and/or directly assigned its costs to functional segments of its retail electric business. The return component of APS' costs reflects a requested 8.67 percent return on its Arizona retail jurisdictional rate base.

Q. IS THE COST-OF-SERVICE METHODOLOGY THAT APS USED REASONABLE?

A. Yes. The methodology basically follows guidelines set in the NARUC *Electric Utility Cost Allocation Manual.* For example, the APS methodology appears to follow traditional cost classifications and allocations for major functional categories of utility service. APS had incorporated a different treatment of transmission costs to comply—according to APS—with requirements instituted by FERC.[2] In my testimony, I have accepted APS' treatment of transmission costs without prejudice since I believe that whether APS' treatment is correct is a legal issue.

Q. DO YOU AGREE WITH APS' CHOICE OF ALLOCATORS TO ASSIGN DEMAND-RELATED PRODUCTION AND TRANSMISSION COSTS?

A. Yes. In allocating demand-related production and transmission costs to major customer classes, APS used the average of its four test-year monthly summer (June-September) coincident system peaks (a 4CP methodology). As APS noted, "Production related and Transmission related assets, and their associated costs, are generally designed and built to enable the Company to meet its system peak load."[3] APS is correct—system peaks are the principal drivers of generation and transmission capacity requirements. The 4CP approach is reasonable and should be approved since it reflects the key determinant of APS' need for bulk power facilities.

Q. WHY IS THE REASONABLENESS OF A COST-OF-SERVICE METHODOLOGY IMPORTANT?

A. Cost of service identifies and assigns cost responsibility to customer classes. Specific rates can then be developed to recover each class' cost-based revenue requirement, resulting in prices that recover the utility's cost of service in an equitable and efficient manner. If the cost-of-service methodology does not allocate and assign cost responsibility in a reasonable manner, then interclass revenue subsidies are created and specific class rates are either over- or under-priced—thereby causing customers to make inefficient electricity investment and consumption decisions.

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[2] See the direct testimony of APS witness Alan Propper at pages 7-10.

[3] Alan Propper, direct testimony at page 5, lines 17-18.

APS has employed a reasonable cost-of-service methodology in this case to allocate and assign its costs to customer classes. However, as I discuss in more detail later, APS deviated from the results of its cost study in assigning its proposed revenue increase to customer classes.

Q. IS APS A SUMMER-PEAKING UTILITY?

A. Yes. As shown in Table 1 below, during the 2002 test year APS' system peaks in June-September were all within 93 percent of its annual peak. The May system peak was the only other monthly peak that was within 80 percent of the annual peak. In all other months, the monthly peaks were only about two-thirds the annual peak.

Table 1. APS' Test-Year Monthly System Peaks

Month	Peak (MW)	Peak/Max (%)
January	3,920.6	68
February	3,828.8	66
March	3,359.3	58
April	3,697.7	64
May	4,985.7	86
June	5,421.1	93
July	5,802.9	100
August	5,685.3	98
September	5,586.5	96
October	3,827.8	66
November	2,976.8	51
December	3,605.8	62

Source: APS response to LCA 11-286(c).

Q. SHOULD MORE MONTHS BE INCLUDED IN THE ALLOCATION FACTOR FOR APS' DEMAND-RELATED GENERATION AND TRANSMISSION COSTS?

A. No. Test-year demands in June-September were at least 1,500 MW greater than peak demands in other months with the exception of May. APS' proposed 4CP methodology is both fair and reasonable.

REVENUE SPREAD

Q. WHAT INCREASE IN REVENUE IS APS REQUESTING?

A. APS has requested a $175-million increase (9.77 percent) in sales revenue, which consists of a $167-million increase in base revenues and APS' proposed $8-million CRCC.

Q. HOW DID APS SPREAD THE PROPOSED REVENUE INCREASE AMONG CUSTOMER CLASSES?

A. APS simply applied an across-the-board 9.31 percent increase (excluding the CRCC) to each major customer class. APS chose this revenue spread and ignored the results of its cost study, which indicated "significant disparities in the rates of return that the different customer classes are providing the Company."[4] In explaining why it did not rely on the results of its cost study in setting rate levels for its major customer classes, APS stated:

> We considered several other factors. Among these the most important were ***rate stability and continuity. For this reason***, the major classes of customers—Residential, General Service, Irrigation, Street Lighting, and Dusk to Dawn—have been given a percentage increase that is approximately the same as the overall requested increase.[5] (emphasis added)

Q. DID APS ACKNOWLEDGE THE INHERENT WEAKNESS OF AN ACROSS-THE-BOARD REVENUE SPREAD?

A. Yes. Concerning the deficiencies of relying on across-the-board revenue spreads, APS states:

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[4] Allan Propper, direct testimony at page 13, lines 10-11.
[5] Allan Propper, direct testimony at page 15, lines 5-9.

> It has been many years since APS has revised the basic structure of its retail rates. The more recent rate changes have generally been made on the basis of "across the board" percentage changes as a result of rate case settlements. This has resulted in some rate distortions that have taken our rates away from tracking costs, both as to rate level and rate design.[6]

Q. WERE THESE "RATE DISTORTIONS" ADDRESSED IN EARLIER APS CASES?

A. Yes. In 1999 when he testified concerning proposed Direct Access rates, APS' witness Alan Propper addressed the interclass rate of return differentials that indicated whether a class was paying above or below cost of service. In developing his proposed Direct Access rates, Mr. Propper indicated that the interclass return differentials should be maintained, but only for a limited time "to ease into cost based rates through a transition period."[7] He justified this approach in the following:

> This approach is consistent with the ACC's stated objective that the transition to competition should not result in rate increases. Immediately eliminating class return differentials would have significant dislocation impacts. The remaining rate of return differentials should be eliminated when Direct Access Service and competition is fully operational. Whether this actually occurs in the market place at the end of the phase-in period or when the Stranded Cost recovery and the CTCs expire cannot be definitively stated at this time. However, ***the elimination of class rate of return differentials should be a major objective of a future rate case***.[8] (emphasis added)

Q. DID APS ADDRESS THE INTERCLASS RATE OF RETURN DIFFERENTIALS IN THIS CASE?

A. No. APS' proposed across-the-board revenue spread ignores the rate of return differentials.

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[6] Alan Propper, direct testimony at page 14, lines 7-11.

[7] See the June 4, 1999 testimony of Alan Propper in Docket No. E-01345A-98-0473, *et al.*, provided in APS' response to RUCO 16-3 at page 15.

[8] Alan Propper, June 4, 1999 testimony in Docket No. E-01345A-98-0473, *et al.*, provided in APS' response to RUCO 16-3 at pages 15-16.

Q. WHAT ARE INTERCLASS REVENUE SUBSIDIES?

A. Interclass subsidies reflect the amount by which revenue from a customer class exceeds or falls short of the class' cost responsibility, which is determined in APS' class cost-of-service study. In general, a class receives (pays) an interclass subsidy if its rate revenue is less than (greater than) its assigned cost of service at the system average rate of return. The existence of large class rate of return differentials often indicates the presence of large interclass revenue subsidies.

Q. ARE RATE OF RETURN DIFFERENTIALS SIGNIFICANT UNDER PRESENT RATES?

A. Yes. As shown in Table 2 below and Exhibit DWG-1, of the five major customer classes that APS serves, four classes—Residential, Irrigation, Street Lighting, and Dusk to Dawn—currently pay rates that are dramatically below cost of service. The rate of return (ROR) indexes for these classes range from 10 to 69. Their below-cost service is subsidized by General Service customers (ROR index of 144) whose present rates are almost $80 million higher than APS' cost of service. This $80-million subsidy goes primarily to Residential customers (nearly $76 million), with the remainder going to the Irrigation and Lighting classes.

Table 2. Interclass Subsidies Under Present Rates ($000)

Class	RORI	Subsidy
Residential	69	75,585
Gen Service	144	(79,913)
Irrigation	10	426
Street Light	40	2,864
Dusk To Dawn	49	1,061
Total Retail	100	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-1.

Q. DOES THIS SITUATION IMPROVE UNDER APS' PROPOSED REVENUE SPREAD?

A. Only minimal improvements occur. APS' proposed revenue spread perpetuates the massive level of interclass revenue subsidies that exist under present rates, and barely moves any customer class closer to cost of service. Moreover, as a result of its proposed revenue spread, APS increased the level of interclass revenue subsidies by about 15 percent—from around $80 million under present rates to more than $92 million under proposed rates. Approximately $87 million of the interclass subsidies created under APS' proposed revenue spread goes to Residential customers. That is, test-year revenues from APS' proposed Residential rates are about $87 million less than APS' costs (as determined in its cost-of-service study) of serving this class. APS makes up this shortfall—as well as the $5.5 million in subsidies received by Irrigation and Lighting customers—by overcharging General Service customers. (See Table 3 below and Exhibit DWG-2, page 2.)

Table 3. Interclass Subsidies Under APS Proposal ($000)

Class	RORI	Subsidy
Residential	74	86,561
Gen Service	137	(92,016)
Irrigation	38	412
Street Light	44	3,668
Dusk To Dawn	52	1,374
Total Retail	100	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-2, page 2.

Q. HOW IS THE GENERAL SERVICE SUBSIDY DISTRIBUTED AMONG THE CLASS SUBGROUPS?

A. APS' cost study identifies four General Service subgroups—Small General Service (SGS), Medium General Service (MGS), Large General Service (LGS), and Extra Large General Service (XLGS). Of these four groups, only rates for

LGS customers are below cost of service—by approximately $2.4 million. In contrast, APS' proposed rates for the SGS, MGS, and XLGS subgroups are around $94 million above costs. (See Table 4 below.)

Table 4. General Service Subsidies Under APS Proposal ($000)

Subgroup	RORI	Subsidy
SGS	137	(35,408)
MGS	145	(45,410)
LGS	91	2,394
XLGS	146	(13,596)

Note: positive (negative) number reflects subsidy received (paid)
Source: APS' response to Staff 6-30.

Q. IS APS' REVENUE SPREAD REASONABLE?

A. No. APS' revenue spread exacerbates the interclass revenue subsidy problem by failing to move rates significantly closer to cost of service. These interclass subsidies are unjustified and should be eliminated—or at a minimum, mitigated by moving rates for each class much closer to cost of service than APS has proposed.

Q. HAVE YOU DEVELOPED AN ALTERNATIVE REVENUE SPREAD THAT MOVES RATES CLOSER TO COST OF SERVICE?

A. Yes. I recommend that the Commission reject APS' proposed revenue spread. No set of reasonable and fair ratemaking objectives can include forcing General Service customers to pay approximately $92 million in interclass revenue subsidies to Residential, Irrigation, and Lighting customers. To take a first and reasonable step in addressing this problem, the Commission should require APS to spread the allowed revenue increase such that classes currently being subsidized get 150 percent of the average system rate increase (excluding the CRCC). Under this proposal, if APS receives its requested 9.31 percent increase in retail base revenues, the Residential, Irrigation, and two Lighting classes would get 13.97 percent increases. General Service customers would get whatever increase is necessary to achieve the overall system average 9.31 percent increase. My analysis indicates that increasing General Service rates by 4.53 percent would achieve this objective. (See Exhibit DWG-3, page 1.)

Q. WHAT EFFECT WOULD YOUR RECOMMENDED REVENUE SPREAD HAVE ON THE COST-TRACKING AND SUBSIDY PROBLEMS THAT APS' PROPOSAL DOES ALMOST NOTHING TO MITIGATE?

A. My proposed revenue spread would move rates for each class significantly closer to cost of service, and also create meaningful reductions in interclass revenue subsidies. Moreover, my recommended revenue spread creates a more equitable and efficient distribution of APS' proposed sales revenue increase without imposing unjust and unreasonable increases on any class. (See Table 5 below and Exhibit DWG-3, page 2.)

Table 5. Interclass Subsidies Under FEA Proposal ($000)

Class	RORI	Subsidy
Residential	86	45,128
Gen Service	120	(49,741)
Irrigation	52	315
Street Light	52	3,166
Dusk To Dawn	61	1,132
Total Retail	100	0

Note: positive (negative) number reflects subsidy received (paid)
Source: Exhibit DWG-3, page 2.

Q. DOES YOUR RECOMMENDED REVENUE SPREAD ELIMINATE INTERCLASS SUBSIDIES?

A. No. My recommended revenue spread only reduces the subsidies by about half. As shown in Table 5 above, Residential customers would still receive a subsidy of more than $45 million, while General Service customers would still pay nearly $50 in revenue subsidies.

Q. IF THE COMMISSION ALLOWS LESS THAN APS' REQUESTED SALES REVENUE INCREASE, HOW SHOULD THE APPROVED INCREASE BE SPREAD?

A. If APS receives a total retail base revenue increase below 9.31 percent but greater than 4.53 percent, I recommend reducing the General Service increase to 2.25 percent and spreading the remaining increase across-the-board to the other major customer classes. If the allowed increase is below 4.53 percent, then the increase for General Service customers should be set at zero and the remaining increase spread across-the-board to the other major customer classes.

Q. HOW SHOULD THE REDUCTION IN THE SUBSIDY PAID BY GENERAL SERVICE CUSTOMERS BE DISTRIBUTED AMONG THE CLASS SUBGROUPS?

A. I recommend that the subsidy reduction be divided proportionately among the SGS, MGS, and XLGS subgroups. Because APS does not have rate schedules that correspond to these General Service subgroup designations, I recognize that LGS customers will also benefit from this subsidy reduction even though they currently pay below cost of service as a subgroup. In my opinion, the subsidy-paying subgroups would gladly live with this problem if their rates were moved significantly closer to cost of service and the subsidy they pay were cut almost in half.

RATE DESIGN

Q. DID YOU EXAMINE EACH OF APS' PROPOSED RATES IN DETAIL?

A. No. My analysis focused on Rates E-34 and E-35, the two rates under which APS serves most Extra Large General Service customers (those with average monthly demands equal to or exceeding 3 MW).

Q. WHAT KEY ELEMENTS ARE REFLECTED IN THE APS-PROPOSED RATES E-34 AND E-35?

A. APS has incorporated four major elements in its design of these rates. In particular, APS has:

- Unbundled the rates to provide both a Bundled Standard Offer Service applicable to customers who continue to purchase their full retail electricity requirements from APS, as well as unbundled pricing components applicable to Direct Access customers.
- Overcharged these XLGS customers by up to $13.6 million.[9] That is, proposed Rates E-34 and E-35 produce test-year electric sales revenues that exceed APS' cost of serving these customers by up to $13.6 million.
- Introduced voltage discounts into the rates—$0.69 per kW for Primary voltage customers and $4.18 per kW for customers served at transmission voltages (that is, 69 kV and higher).
- Added May to the current June-October summer billing months used to determine 80-percent ratchet billing demands. Such ratchet demands become the customer's monthly billing kW[10] if they exceed the customer's highest 15-minute demand in the current month.
- Added two hours to the daily on-peak period in Rate E-35—moving from 11 a.m. – 9 p.m. Monday-Friday under the current rate to 9 a.m. – 9 p.m. under APS' proposed Rate E-35.

[9] The exact amount of overcharge cannot be determined because APS' cost analysis is done by major customer group classifications, not by classes defined according to rate schedule designations. The $13.6 million reflects the interclass revenue subsidy paid by XLGS customers under APS' proposed revenue spread. Since not all XLGS customers are served under Rates E-34 and E-35, the total overcharge for customers served under these rates will likely be less than $13.6 million.

[10] On-peak billing kW in Rate E-35.

Q. DO YOU HAVE ANY MAJOR CONCERNS WITH THESE KEY RATE DESIGN ELEMENTS?

A. Yes. I do not object to the manner in which APS has unbundled the rates. However, I have major concerns with each of the other key rate design elements. Because I have already discussed the subsidy issue concerning General Service rates, I will focus my discussion on the proposed voltage discounts and the changes in the peak measurement periods.

Q. SHOULD RATES E-34 AND E-35 INCLUDE VOLTAGE DISCOUNTS?

A. Yes. Customers served under these rates take delivery service at transmission, primary, and secondary voltages as defined by APS. The cost of serving customers at different voltages varies because of differences in the types and cost of equipment needed to deliver service and energy losses that increase as the service delivery voltage decreases.

Voltage discounts usually appear as discounts to stated energy charges (to reflect losses) and/or demand charges (to reflect capacity cost differentials). APS has chosen to offer only discounts to its stated demand charges—$0.69 per kW for Primary voltage customers and $4.18 per kW for customers served at transmission voltages (that is, 69 kV and higher). While I have no problem with the concept of voltage discounts to reflect actual cost differences, such discounts should be based on cost analyses that clearly demonstrate their validity. Unfortunately, APS did not provide such analyses either in Mr. Propper's testimony or in response to FEA data requests.

Q. WERE YOU ABLE TO EVALUATE THE REASONABLENESS OF THE PROPOSED VOLTAGE DISCOUNTS DESPITE THE LACK OF CLEARLY DEFINED ANALYSES BY APS?

A. Yes. I used information provided by APS regarding its unbundled cost of service[11] to determine that APS had overstated the Transmission voltage discount and understated the Primary discount.

Q. DO THE PROPOSED VOLTAGE DISCOUNTS CREATE OTHER PROBLEMS?

A. Yes. Because of the large Transmission voltage discount that APS has proposed, transmission customers served under Rates E-34 and E-35 would receive base rate ***decreases*** while secondary and primary service customers would receive large rate increases.[12] In my opinion, rates should be designed, if possible, such that no major customer subgroup receives a rate decrease while other customers served under the same rate(s) receive large rate increases.

Q. WHY ARE YOU CONCERNED ABOUT APS' PROPOSED CHANGES IN THE PEAK MEASUREMENT PERIODS?

A. My concerns are twofold. First, APS has not justified extending either the summer billing months or the daily on-peak period. In particular, APS has not demonstrated that the changes are justified or necessary to ensure that costs are tracked properly and accurately. Simply changing the peak measurement periods to match such periods in other rates is not an adequate justification. Second, I do not believe that APS' proposed rates reflect the potential revenue impacts of lengthening these periods—that is, reflect the incremental revenue increase that it would likely receive if these periods were lengthened. If, as I suspect, the potential revenue impacts are not reflected in APS' proposed rates, then these rates will likely recover too much revenue.

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[11] See specifically APS' response to Staff 6-30 and workpapers AP_WP8 and AP_WP9.

Q. WHAT SPECIFIC CHANGES ARE YOU RECOMMENDING TO APS' PROPOSED RATES E-34 AND E-35?

A. I recommend:

- Reducing the proposed Transmission voltage discount from $4.18 per kW to $3.30 per kW, and increasing APS' proposed Primary voltage discount from $0.69 per kW to $1.40 per kW. These changes are necessary not only to make the discounts more cost based, but also to reduce the likelihood that transmission voltage customers using Rates 34 and 35 receive rate decreases as they do under APS' rate design.
- Increasing the peak and off-peak energy charge differential in Rate E-35 to encourage more efficient electricity usage.
- Maintaining not only the current summer billing months (June-October) used to determine 80 percent ratchet billing demands in both rates, but also the 11 a.m. – 9 p.m. Monday-Friday on-peak period in Rate E-35.

Q. HAVE YOU SUMMARIZED YOUR RECOMMENDED CHARGES FOR RATES E-34 AND E-35?

A. Yes. My recommended charges for Rates E-34 and E-35 are shown in Exhibits DWG-4 and DWG-5, respectively.

Q. DID YOU ESTIMATE THE IMPACTS OF YOUR RECOMMENDED RATES ON CUSTOMER BILLS?

A. Yes. These estimated impacts are shown in Exhibits DWG-6 (Rate E-34) and DWG-7 (Rate E-35). In general, the increases are more uniform across load factors compared to increases under APS' proposed rates. However, my recommended rates still produce rate decreases for some transmission customers,

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[12] No transmission service customers are currently served under Rate E-34 according to workpaper AP_WP9.

although the decreases are not as large as those under the APS rates. This is a rate design problem that all parties should work together to resolve in this case.

Q. DO YOUR RATES REFLECT REVENUE REDUCTIONS THAT YOU HAVE RECOMMENDED FOR GENERAL SERVICE CUSTOMERS?

A. No. My recommended rates were designed to recover the same level of revenue that is produced under APS' proposed rates.

Q. SHOULD THE COMMISSION APPROVE YOUR RECOMMENDED RATES E-34 AND E-35?

A. Yes. The Commission should reject APS' proposed design of Rates E-34 and E-35. Instead, the Commission should approve revisions to these rates that modify selected demand and energy charges, including the proposed voltage discounts. These changes are reasonable and justified on the basis of APS' cost of service.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF ARIZONA
BEFORE THE
ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-03-0437

IN THE MATTER OF THE ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT

EXHIBITS TO THE DIRECT TESTIMONY OF
DR. DENNIS W. GOINS
ON BEHALF OF THE
FEDERAL EXECUTIVE AGENCIES

February 3, 2004

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *APS Present Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction: Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	1,827,189	1,791,584 (a)	35,605	889,898 (a)	883,595 (a)	2,099 (a)	10,794 (a)	5,198 (a)
1.b.	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132 (b)	36,432	839,733 (b)	730,686 (b)	2,360 (b)	12,439 (b)	4,914 (b)
3.	Operating Income Before Income Taxes	351,613	350,014	1,598	121,352	227,158	(46)	937	613
4.	Income Taxes	86,608	86,144	463	18,616	67,806	(75)	(195)	(7)
5.	Net Operating Income	265,005	263,870	1,135	102,736	159,352	29	1,132	620
6.	Rate Base	4,221,019	4,207,476 (c)	13,543	2,367,112 (c)	1,769,998 (c)	4,571 (c)	45,676 (c)	20,118 (c)
7.	Rate of Return	6.28%	6.27%	8.38%	4.34%	9.00%	0.63%	2.48%	3.08%
				ROR Index	69	144	10	40	49
				Subsidy* Received(Paid)	75,565	(79,913)	426	2,864	1,061

Source: APS response to FEA 1-9, RC002865
See APS Schedule G-1

Supporting APS Schedules:
(a) H-1
(b) G-4
(c) G-3

* Subsidy indicates change in Rate Revenue required to earn 6.27% return on rate base.
Gross Revenue Conversion Factor = 1.6529 APS Sched C-3
COS ROR = 6.2715%

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PRESENT AND PROPOSED RATES
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year (a)		APS Proposed Increase (b)				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates 1) ($000)	Proposed Rates 3) 4) ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Proposed CRCC 2) ($000)	Proposed Increase with CRCC % [(E) + (C)] / (A)	Line No.
1	Residential	889,898	972,747	82,849	9.31%	3,737	9.73%	1
2	General Service	883,595	965,868	82,273	9.31%	4,485	9.82%	2
3	Irrigation	2,099	2,295	196	9.34%	11	9.86%	3
4	Outdoor Lighting	10,794	11,799	1,005	9.31%	36	9.64%	4
5	Dusk to Dawn Lighting Service	5,198	5,682	484	9.31%	14	9.58%	5
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,283	9.77%	6

Source: APS Schedule H-1
(a) Supporting Schedules: H-2

(b) Recap Schedules: A-1

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.
3) Please note that the Proposed Increase shown on this schedule does not directly match the Proposed Increase on Schedule H-2 for the General Service and Irrigation classes. Schedule H-2 assumes customer migration from Irrigation to General Service due to more favorable rates. The total proposed revenue for both Irrigation and General Service classes on these two schedules match.
4) The total proposed revenue for both Outdoor Lighting and Dusk to Dawn classes on this schedule matches the total proposed revenue for both classes on Schedule H-2.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *APS Proposed Rates*
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction				
					Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	1,993,996	1,958,391 (a)	35,605	972,747 (a)	965,868 (a)	2,295 (a)	11,799 (a)	5,682 (a)
1.b.	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132 (b)	36,432	839,733 (b)	730,686 (b)	2,360 (b)	12,439 (b)	4,914 (b)
3.	Operating Income Before Income Taxes	518,420	516,821	1,598	204,201	309,431	150	1,942	1,097
4.	Income Taxes	152,496	152,033	463	51,968	99,684	1	197	183
5.	Net Operating Income	365,924	364,788	1,135	152,233	209,747	149	1,745	914
6.	Rate Base	4,221,019	4,207,476 (c)	13,543	2,367,112 (c)	1,769,998 (c)	4,571 (c)	45,676 (c)	20,118 (c)
7.	Rate of Return	8.67%	8.67%	8.38%	6.43%	11.85%	3.26%	3.82%	4.54%
				ROR Index	74	137	38	44	52
				Subsidy* Received(Paid)	86,561	(92,016)	412	3,668	1,374

Source: APS response to FEA 1-9, RC002686
See APS Schedule G-2

Supporting APS Schedules:
(a) H-1
(b) G-4
(c) G-3

* Subsidy indicates change in Rate Revenue required to earn 8.67% return on rate base.
Class Revenue Requirement at 8.67% ROR from APS response to FEA 1-8(c), RC002681
COS ROR = 8.67%

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
APS PRESENT RATES AND FEA PROPOSED REVENUE SPREAD
TEST YEAR ENDING DECEMBER 31, 2002, ADJUSTED

		Base Revenues in the Test Year (a)		FEA Proposed Spread				
		(A)	(B)	(C)	(D)	(E)	(F)	
Line No.	Customer Classification	Present Rates [1] ($000)	FEA Proposed Spread ($000)	Amount ($000) (B) - (A)	% (C) / (A)	Proposed CRCC [2] ($000)	Proposed Increase with CRCC % [(E) + (C)] / (A)	Line No.
1	Residential	889,898	1,014,180	124,282	13.97%	3,737	14.39%	1
2	General Service	883,595	923,593	39,998	4.53%	4,485	5.03%	2
3	Irrigation	2,099	2,392	293	13.97%	11	14.49%	3
4	Outdoor Lighting	10,794	12,301	1,507	13.97%	36	14.30%	4
5	Dusk to Dawn Lighting Service	5,198	5,924	726	13.97%	14	14.24%	5
6	Total Sales to Ultimate Retail Customers	1,791,584	1,958,391	166,807	9.31%	8,283	9.77%	6

Source: APS Schedule H-1 and APS response to FEA 1-8(c), RC002681
(a) Supporting Schedules: H-2

Limit on class increase = 150% system avg

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments such as rate decreases and removal of franchise fees from base rates.
2) The CRCC is the Competition Rules Compliance Charge as proposed in ACC Docket No. E-01345A-02-0403. The proposed CRCC will be in place for five years.

ARIZONA PUBLIC SERVICE COMPANY
Cost of Service Summary - *FEA Proposed Revenue Spread*
Rates of Return by Customer Classification
Adjusted Test Year Ending December 31, 2002
($000)

		Total Company	Total ACC Jurisdiction	All Other	Total ACC Jurisdiction: Residential	General Service	Irrigation	Street Lighting	Dusk to Dawn
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1.a.	Revenues from Rates	1,993,996	1,958,391 (a)	35,605	1,014,180	923,593	2,392	12,301	5,924
1.b.	Other Revenues	150,987	148,562	2,425	71,187	74,249	215	2,582	329
2.	Expenses	1,626,563	1,590,132 (b)	36,432	839,733 (a)	730,686 (a)	2,360 (a)	12,439 (a)	4,914 (a)
3.	Operating Income Before Income Taxes	518,420	516,821	1,598	245,634	267,156	247	2,444	1,339
4.	Income Taxes	152,496	152,033	463	68,334	82,985	39	395	279
5.	Net Operating Income	365,924	364,788	1,135	177,300	184,171	208	2,049	1,060
6.	Rate Base	4,221,019	4,207,476 (c)	13,543	2,367,112 (b)	1,769,998 (b)	4,571 (b)	45,676 (b)	20,118 (b)
7.	Rate of Return	8.67%	8.67%	8.38%	7.49%	10.41%	4.55%	4.49%	5.27%
				ROR Index	86	120	52	52	61
				Subsidy* Received(Paid)	45,128	(49,741)	315	3,166	1,132

Source: APS response to FEA 1-9, RC002686
See APS Schedule G-2

Supporting APS Schedules:
(a) G-4
(b) G-3

* Subsidy indicates change in Rate Revenue required to earn 8.67% return on rate base.
Class Revenue Requirement at 8.67% ROR from APS response to FEA 1-8(c), RC002681
COS ROR = 8.67%
Incremental tax rate = 39.50% APS Sch C-3

Arizona Public Service
Docket No. E-01345A-03

Rate E-34

Rate E-34 Present

BSC	2,430.00	per mo
Demand	10.61	per kW
Energy	0.03126	per kWh

Rate E-34: APS Proposed

Bundled

BSC			
	SCM	0.575	per day
	IRM	1.134	per day
	Pri	2.926	per day
	Trans	22.422	per day
Demand			
	Sec	13.062	per kW
	Pri	12.372	per kW
	Trans	8.882	per kW
Energy		0.03284	per kWh
Discounts			
	Primary	(0.69)	
	Transmission	(4.18)	

Unbundled

BSC		0.108	per day
RevCyc-M			
	SCM	0.345	per day
	IRM	0.904	per day
	Pri	2.696	per day
	Trans	22.192	per day
RevCyc-MR		0.058	per day
RevCyc-B		0.064	per day
SysBenefits		0.00161	per kWh
Trans		0.00476	per kWh
DistribChrg			
	Sec	4.782	per kW
	Pri	4.092	per kW
	Trans	0.602	per kW +
	Energy	0.00134	per kWh
Generation			
	Dem	8.280	per kW +
	Energy	0.02513	per kWh

Rate E-34: FEA Proposed

Bundled

BSC			
	SCM	0.575	per day
	IRM	1.134	per day
	Pri	2.926	per day
	Trans	22.422	per day
Demand			
	Sec	12.984	per kW
	Pri	11.584	per kW
	Trans	9.584	per kW
Energy		0.03306	per kWh
Discounts			
	Primary	(1.40)	
	Transmission	(3.40)	

Unbundled

BSC		0.108	per day
RevCyc-M			
	SCM	0.345	per day
	IRM	0.904	per day
	Pri	2.696	per day
	Trans	22.192	per day
RevCyc-MR		0.058	per day
RevCyc-B		0.064	per day
SysBenefits		0.00161	per kWh
Trans		0.00476	per kWh
DistribChrg			
	Sec	3.884	per kW
	Pri	2.484	per kW
	Trans	0.484	per kW +
	Energy	0.00100	per kWh
Generation			
	Dem	9.100	per kW +
	Energy	0.02569	per kWh

Arizona Public Service
Docket No. E-01345A-03

Rate E-35

Rate E-35 Present

BSC		2,450.00	per mo
Demand			
	Reg	13.50	per kW
	Excess	6.53	per kW
Energy			
	Peak	0.03605	per kWh
	Off	0.02105	per kWh

Rate E-35: APS Proposed

Bundled

		Reg	Excess	
BSC				
	SCM	0.600		per day
	IRM	1.134		per day
	Pri	2.926		per day
	Trans	22.422		per day
Demand		Reg	Excess	
	Sec	13.598	6.717	per kW
	Pri	12.908	6.027	per kW
	Trans	9.418	2.537	per kW
Energy				
	Peak	0.03618		per kWh
	Off	0.02868		per kWh
Discounts				
	Primary	(0.690)		
	Transmission	(4.180)		

Unbundled

BSC		0.108		per day
RevCyc-M				
	SCM	0.370		per day
	IRM	0.904		per day
	Pri	2.696		per day
	Trans	22.192		per day
RevCyc-MR		0.058		per day
RevCyc-B		0.064		per day
SysBenefits		0.00161		per kWh
Trans		0.00476		per kWh
DistribChrg		Reg	Excess	
	Sec	4.423	4.423	per kW
	Pri	3.733	3.733	per kW
	Trans	0.243	0.243	per kW +
	Energy	0.001		per kWh
Generation				
	Dem-Pk	9.175		per kW +
	Energy-Pk	0.02914		per kWh
	Energy-Off	0.02164		per kWh

Rate E-35: FEA Proposed

Bundled

BSC				
	SCM	0.600		per day
	IRM	1.134		per day
	Pri	2.926		per day
	Trans	22.422		per day
Demand		Reg	Excess	
	Sec	13.200	6.600	per kW
	Pri	11.800	5.200	per kW
	Trans	9.800	3.200	per kW
Energy				
	Peak	0.04027		per kWh
	Off	0.02703		per kWh
Discounts				
	Primary	(1.400)		
	Transmission	(3.400)		
Days/Mo=		30.41667		

Unbundled

BSC		0.108		per day
RevCyc-M				
	SCM	0.370		per day
	IRM	0.904		per day
	Pri	2.696		per day
	Trans	22.192		per day
RevCyc-MR		0.058		per day
RevCyc-B		0.064		per day
SysBenefits		0.00161		per kWh
Trans		0.00476		per kWh
DistribChrg		Reg	Excess	
	Sec	4.100	4.100	per kW
	Pri	2.700	2.700	per kW
	Trans	0.700	0.700	per kW +
	Energy	0.00066		per kWh
Generation				
	Dem-Pk	9.100		per kW +
	Energy-Pk	0.03324		per kWh
	Energy-Off	0.02000		per kWh

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-34 - Secondary

Customer Bills at Varying Consumption Levels at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC (C) x $0.000353	Franchise [(E) + (F)] x 0.0144	Monthly Bill under Proposed Rates (E) + (F) + (G)	Amount ($) (H) - (D)	% (I) / (D)
3,000	20%	438,000	47,951.88	53,466.30	154.61	772.14	54,393.05	6,441.17	13.4%
3,000	30%	657,000	54,797.82	60,706.44	231.92	877.51	61,815.87	7,018.05	12.8%
3,000	40%	876,000	61,643.76	67,946.58	309.23	982.88	69,238.69	7,594.93	12.3%
3,000	50%	1,095,000	68,489.70	75,186.72	386.54	1,088.25	76,661.51	8,171.81	11.9%
3,000	75%	1,642,500	85,604.55	93,287.07	579.80	1,351.68	95,218.55	9,614.00	11.2%
3,500	20%	511,000	55,538.86	62,371.68	180.38	900.75	63,452.81	7,913.95	14.2%
3,500	30%	766,500	63,525.79	70,818.51	270.57	1,023.68	72,112.76	8,586.97	13.5%
3,500	40%	1,022,000	71,512.72	79,265.34	360.77	1,146.62	80,772.73	9,260.01	12.9%
3,500	50%	1,277,500	79,499.65	87,712.17	450.96	1,269.55	89,432.68	9,933.03	12.5%
3,500	75%	1,916,250	99,466.98	108,829.25	676.44	1,576.88	111,082.57	11,615.59	11.7%
4,000	20%	584,000	63,125.84	71,277.06	206.15	1,029.36	72,512.57	9,386.73	14.9%
4,000	30%	876,000	72,253.76	80,930.58	309.23	1,169.85	82,409.66	10,155.90	14.1%
4,000	40%	1,168,000	81,381.68	90,584.10	412.30	1,310.35	92,306.75	10,925.07	13.4%
4,000	50%	1,460,000	90,509.60	100,237.62	515.38	1,450.84	102,203.84	11,694.24	12.9%
4,000	75%	2,190,000	113,329.40	124,371.42	773.07	1,802.08	126,946.57	13,617.17	12.0%
4,500	20%	657,000	70,712.82	80,182.44	231.92	1,157.97	81,572.33	10,859.51	15.4%
4,500	30%	985,500	80,981.73	91,042.65	347.88	1,316.02	92,706.55	11,724.82	14.5%
4,500	40%	1,314,000	91,250.64	101,902.86	463.84	1,474.08	103,840.78	12,590.14	13.8%
4,500	50%	1,642,500	101,519.55	112,763.07	579.80	1,632.14	114,975.01	13,455.46	13.3%
4,500	75%	2,463,750	127,191.83	139,913.60	869.70	2,027.28	142,810.58	15,618.75	12.3%
5,000	20%	730,000	78,299.80	89,087.82	257.69	1,286.58	90,632.09	12,332.29	15.8%
5,000	30%	1,095,000	89,709.70	101,154.72	386.54	1,462.19	103,003.45	13,293.75	14.8%
5,000	40%	1,460,000	101,119.60	113,221.62	515.38	1,637.81	115,374.81	14,255.21	14.1%
5,000	50%	1,825,000	112,529.50	125,288.52	644.23	1,813.43	127,746.18	15,216.68	13.5%
5,000	75%	2,737,500	141,054.25	155,455.77	966.34	2,252.48	158,674.59	17,620.34	12.5%
6,000	20%	876,000	93,473.76	106,898.58	309.23	1,543.79	108,751.60	15,277.84	16.3%
6,000	30%	1,314,000	107,165.64	121,378.86	463.84	1,754.53	123,597.23	16,431.59	15.3%
6,000	40%	1,752,000	120,857.52	135,859.14	618.46	1,965.28	138,442.88	17,585.36	14.6%
6,000	50%	2,190,000	134,549.40	150,339.42	773.07	2,176.02	153,288.51	18,739.11	13.9%
6,000	75%	3,285,000	168,779.10	186,540.12	1,159.61	2,702.88	190,402.61	21,623.51	12.8%
7,000	20%	1,022,000	108,647.72	124,709.34	360.77	1,801.01	126,871.12	18,223.40	16.8%
7,000	30%	1,533,000	124,621.58	141,603.00	541.15	2,046.88	144,191.03	19,569.45	15.7%
7,000	40%	2,044,000	140,595.44	158,496.66	721.53	2,292.74	161,510.93	20,915.49	14.9%
7,000	50%	2,555,000	156,569.30	175,390.32	901.92	2,538.61	178,830.85	22,261.55	14.2%
7,000	75%	3,832,500	196,503.95	217,624.47	1,352.87	3,153.27	222,130.61	25,626.66	13.0%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-34 - Primary

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Monthly Bill	Components of Proposed Bill			Monthly Bill	Change	
kW	Load Factor	Monthly kWh	under Present Rates	Base	CRCC	Franchise	under Proposed Rates	Amount ($)	%
					(C) x $0.000353	[(E) + (F)] x 0.0144	(E) + (F) + (G)	(H) - (D)	(I) / (D)
3,000	20%	438,000	47,951.88	49,320.06	154.61	712.44	50,187.11	2,235.23	4.7%
3,000	30%	657,000	54,797.82	56,560.20	231.92	817.81	57,609.93	2,812.11	5.1%
3,000	40%	876,000	61,643.76	63,800.34	309.23	923.18	65,032.75	3,388.99	5.5%
3,000	50%	1,095,000	68,489.70	71,040.48	386.54	1,028.55	72,455.57	3,965.87	5.8%
3,000	75%	1,642,500	85,604.55	89,140.83	579.80	1,291.98	91,012.61	5,408.06	6.3%
3,500	20%	511,000	55,538.86	57,525.44	180.38	830.96	58,536.78	2,997.92	5.4%
3,500	30%	766,500	63,525.79	65,972.27	270.57	953.90	67,196.74	3,670.95	5.8%
3,500	40%	1,022,000	71,512.72	74,419.10	360.77	1,076.83	75,856.70	4,343.98	6.1%
3,500	50%	1,277,500	79,499.65	82,865.93	450.96	1,199.76	84,516.65	5,017.00	6.3%
3,500	75%	1,916,250	99,466.98	103,983.01	676.44	1,507.10	106,166.55	6,699.57	6.7%
4,000	20%	584,000	63,125.84	65,730.82	206.15	949.49	66,886.46	3,760.62	6.0%
4,000	30%	876,000	72,253.76	75,384.34	309.23	1,089.99	76,783.56	4,529.80	6.3%
4,000	40%	1,168,000	81,381.68	85,037.86	412.30	1,230.48	86,680.64	5,298.96	6.5%
4,000	50%	1,460,000	90,509.60	94,691.38	515.38	1,370.98	96,577.74	6,068.14	6.7%
4,000	75%	2,190,000	113,329.40	118,825.18	773.07	1,722.21	121,320.46	7,991.06	7.1%
4,500	20%	657,000	70,712.82	73,936.20	231.92	1,068.02	75,236.14	4,523.32	6.4%
4,500	30%	985,500	80,981.73	84,796.41	347.88	1,226.08	86,370.37	5,388.64	6.7%
4,500	40%	1,314,000	91,250.64	95,656.62	463.84	1,384.13	97,504.59	6,253.95	6.9%
4,500	50%	1,642,500	101,519.55	106,516.83	579.80	1,542.19	108,638.82	7,119.27	7.0%
4,500	75%	2,463,750	127,191.83	133,667.36	869.70	1,937.33	136,474.39	9,282.56	7.3%
5,000	20%	730,000	78,299.80	82,141.58	257.69	1,186.55	83,585.82	5,286.02	6.8%
5,000	30%	1,095,000	89,709.70	94,208.48	386.54	1,362.17	95,957.19	6,247.49	7.0%
5,000	40%	1,460,000	101,119.60	106,275.38	515.38	1,537.79	108,328.55	7,208.95	7.1%
5,000	50%	1,825,000	112,529.50	118,342.28	644.23	1,713.41	120,699.92	8,170.42	7.3%
5,000	75%	2,737,500	141,054.25	148,509.53	966.34	2,152.45	151,628.32	10,574.07	7.5%
6,000	20%	876,000	93,473.76	98,552.34	309.23	1,423.61	100,285.18	6,811.42	7.3%
6,000	30%	1,314,000	107,165.64	113,032.62	463.84	1,634.35	115,130.81	7,965.17	7.4%
6,000	40%	1,752,000	120,857.52	127,512.90	618.46	1,845.09	129,976.45	9,118.93	7.5%
6,000	50%	2,190,000	134,549.40	141,993.18	773.07	2,055.83	144,822.08	10,272.68	7.6%
6,000	75%	3,285,000	168,779.10	178,193.88	1,159.61	2,582.69	181,936.18	13,157.08	7.8%
7,000	20%	1,022,000	108,647.72	114,963.10	360.77	1,660.66	116,984.53	8,336.81	7.7%
7,000	30%	1,533,000	124,621.58	131,856.76	541.15	1,906.53	134,304.44	9,682.86	7.8%
7,000	40%	2,044,000	140,595.44	148,750.42	721.53	2,152.40	151,624.35	11,028.91	7.8%
7,000	50%	2,555,000	156,569.30	165,644.08	901.92	2,398.26	168,944.26	12,374.96	7.9%
7,000	75%	3,832,500	196,503.95	207,878.23	1,352.87	3,012.93	212,244.03	15,740.08	8.0%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-34 - Transmission

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
				Components of Proposed Bill				Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC (C) x $0.000353	Franchise [(E) + (F)] x 0.0144	Monthly Bill under Proposed Rates (E) + (F) + (G)	Amount ($) (H) - (D)	% (I) / (D)
3,000	20%	438,000	47,951.88	43,904.94	154.61	634.46	44,694.01	(3,257.87)	-6.8%
3,000	30%	657,000	54,797.82	51,145.08	231.92	739.83	52,116.83	(2,680.99)	-4.9%
3,000	40%	876,000	61,643.76	58,385.22	309.23	845.20	59,539.65	(2,104.11)	-3.4%
3,000	50%	1,095,000	68,489.70	65,625.36	386.54	950.57	66,962.47	(1,527.23)	-2.2%
3,000	75%	1,642,500	85,604.55	83,725.71	579.80	1,214.00	85,519.51	(85.04)	-0.1%
3,500	20%	511,000	55,538.86	51,110.32	180.38	738.59	52,029.29	(3,509.57)	-6.3%
3,500	30%	766,500	63,525.79	59,557.15	270.57	861.52	60,689.24	(2,836.55)	-4.5%
3,500	40%	1,022,000	71,512.72	68,003.98	360.77	984.45	69,349.20	(2,163.52)	-3.0%
3,500	50%	1,277,500	79,499.65	76,450.81	450.96	1,107.39	78,009.16	(1,490.49)	-1.9%
3,500	75%	1,916,250	99,466.98	97,567.89	676.44	1,414.72	99,659.05	192.07	0.2%
4,000	20%	584,000	63,125.84	58,315.70	206.15	842.71	59,364.56	(3,761.28)	-6.0%
4,000	30%	876,000	72,253.76	67,969.22	309.23	983.21	69,261.66	(2,992.10)	-4.1%
4,000	40%	1,168,000	81,381.68	77,622.74	412.30	1,123.70	79,158.74	(2,222.94)	-2.7%
4,000	50%	1,460,000	90,509.60	87,276.26	515.38	1,264.20	89,055.84	(1,453.76)	-1.6%
4,000	75%	2,190,000	113,329.40	111,410.06	773.07	1,615.44	113,798.57	469.17	0.4%
4,500	20%	657,000	70,712.82	65,521.08	231.92	946.84	66,699.84	(4,012.98)	-5.7%
4,500	30%	985,500	80,981.73	76,381.29	347.88	1,104.90	77,834.07	(3,147.66)	-3.9%
4,500	40%	1,314,000	91,250.64	87,241.50	463.84	1,262.96	88,968.30	(2,282.34)	-2.5%
4,500	50%	1,642,500	101,519.55	98,101.71	579.80	1,421.01	100,102.52	(1,417.03)	-1.4%
4,500	75%	2,463,750	127,191.83	125,252.24	869.70	1,816.16	127,938.10	746.27	0.6%
5,000	20%	730,000	78,299.80	72,726.46	257.69	1,050.97	74,035.12	(4,264.68)	-5.4%
5,000	30%	1,095,000	89,709.70	84,793.36	386.54	1,226.59	86,406.49	(3,303.21)	-3.7%
5,000	40%	1,460,000	101,119.60	96,860.26	515.38	1,402.21	98,777.85	(2,341.75)	-2.3%
5,000	50%	1,825,000	112,529.50	108,927.16	644.23	1,577.83	111,149.22	(1,380.28)	-1.2%
5,000	75%	2,737,500	141,054.25	139,094.41	966.34	2,016.87	142,077.62	1,023.37	0.7%
6,000	20%	876,000	93,473.76	87,137.22	309.23	1,259.23	88,705.68	(4,768.08)	-5.1%
6,000	30%	1,314,000	107,165.64	101,617.50	463.84	1,469.97	103,551.31	(3,614.33)	-3.4%
6,000	40%	1,752,000	120,857.52	116,097.78	618.46	1,680.71	118,396.95	(2,460.57)	-2.0%
6,000	50%	2,190,000	134,549.40	130,578.06	773.07	1,891.46	133,242.59	(1,306.81)	-1.0%
6,000	75%	3,285,000	168,779.10	166,778.76	1,159.61	2,418.31	170,356.68	1,577.58	0.9%
7,000	20%	1,022,000	108,647.72	101,547.98	360.77	1,467.49	103,376.24	(5,271.48)	-4.9%
7,000	30%	1,533,000	124,621.58	118,441.64	541.15	1,713.35	120,696.14	(3,925.44)	-3.1%
7,000	40%	2,044,000	140,595.44	135,335.30	721.53	1,959.22	138,016.05	(2,579.39)	-1.8%
7,000	50%	2,555,000	156,569.30	152,228.96	901.92	2,205.08	155,335.96	(1,233.34)	-0.8%
7,000	75%	3,832,500	196,503.95	194,463.11	1,352.87	2,819.75	198,635.73	2,131.78	1.1%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-35 - Secondary

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					Components of Proposed Bill				Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC (D) x $0.000353	Franchise [(F) + (G)] x 0.0144	Monthly Bill under Proposed Rates (F) + (G) + (H)	Amount ($) (I) - (E)	% (J) / (E)
2,500	3,000	20%	438,000	46,528.70	46,844.86	154.61	676.79	47,676.26	1,147.56	2.5%
2,500	3,000	30%	657,000	52,255.55	53,750.28	231.92	777.34	54,759.54	2,503.99	4.8%
2,500	3,000	40%	876,000	57,982.40	60,655.70	309.23	877.89	61,842.82	3,860.42	6.7%
2,500	3,000	50%	1,095,000	63,709.25	67,561.12	386.54	978.45	68,926.11	5,216.86	8.2%
2,500	3,000	75%	1,642,500	78,026.38	84,824.67	579.80	1,229.82	86,634.29	8,607.91	11.0%
2,900	3,500	20%	511,000	53,657.65	54,426.67	180.38	786.34	55,393.39	1,735.74	3.2%
2,900	3,500	30%	766,500	60,338.98	62,482.99	270.57	903.65	63,657.21	3,318.23	5.5%
2,900	3,500	40%	1,022,000	67,020.30	70,539.32	360.77	1,020.96	71,921.05	4,900.75	7.3%
2,900	3,500	50%	1,277,500	73,701.63	78,595.64	450.96	1,138.27	80,184.87	6,483.24	8.8%
2,900	3,500	75%	1,916,250	90,404.94	98,736.45	676.44	1,431.55	100,844.44	10,439.50	11.5%
3,300	4,000	20%	584,000	60,786.60	62,008.47	206.15	895.89	63,110.51	2,323.91	3.8%
3,300	4,000	30%	876,000	68,422.40	71,215.70	309.23	1,029.96	72,554.89	4,132.49	6.0%
3,300	4,000	40%	1,168,000	76,058.20	80,422.93	412.30	1,164.03	81,999.26	5,941.06	7.8%
3,300	4,000	50%	1,460,000	83,694.00	89,630.16	515.38	1,298.10	91,443.64	7,749.64	9.3%
3,300	4,000	75%	2,190,000	102,783.50	112,648.22	773.07	1,633.27	115,054.56	12,271.06	11.9%
3,500	4,500	20%	657,000	65,305.55	66,950.28	231.92	967.42	68,149.62	2,844.07	4.4%
3,500	4,500	30%	985,500	73,895.83	77,308.41	347.88	1,118.25	78,774.54	4,878.71	6.6%
3,500	4,500	40%	1,314,000	82,486.10	87,666.54	463.84	1,269.08	89,399.46	6,913.36	8.4%
3,500	4,500	50%	1,642,500	91,076.38	98,024.67	579.80	1,419.90	100,024.37	8,947.99	9.8%
3,500	4,500	75%	2,463,750	112,552.06	123,920.00	869.70	1,796.97	126,586.67	14,034.61	12.5%
4,000	5,000	20%	730,000	73,739.50	75,852.09	257.69	1,095.98	77,205.76	3,466.26	4.7%
4,000	5,000	30%	1,095,000	83,284.25	87,361.12	386.54	1,263.57	89,011.23	5,726.98	6.9%
4,000	5,000	40%	1,460,000	92,829.00	98,870.16	515.38	1,431.15	100,816.69	7,987.69	8.6%
4,000	5,000	50%	1,825,000	102,373.75	110,379.19	644.23	1,598.74	112,622.16	10,248.41	10.0%
4,000	5,000	75%	2,737,500	126,235.63	139,151.78	966.34	2,017.70	142,135.82	15,900.19	12.6%
4,500	6,000	20%	876,000	84,082.40	87,055.70	309.23	1,258.05	88,622.98	4,540.58	5.4%
4,500	6,000	30%	1,314,000	95,536.10	100,866.54	463.84	1,459.16	102,789.54	7,253.44	7.6%
4,500	6,000	40%	1,752,000	106,989.80	114,677.38	618.46	1,660.26	116,956.10	9,966.30	9.3%
4,500	6,000	50%	2,190,000	118,443.50	128,488.22	773.07	1,861.36	131,122.65	12,679.15	10.7%
4,500	6,000	75%	3,285,000	147,077.75	163,015.33	1,159.61	2,364.12	166,539.06	19,461.31	13.2%
5,200	7,000	20%	1,022,000	97,035.30	100,899.32	360.77	1,458.15	102,718.24	5,682.94	5.9%
5,200	7,000	30%	1,533,000	110,397.95	117,011.96	541.15	1,692.76	119,245.87	8,847.92	8.0%
5,200	7,000	40%	2,044,000	123,760.60	133,124.61	721.53	1,927.38	135,773.52	12,012.92	9.7%
5,200	7,000	50%	2,555,000	137,123.25	149,237.26	901.92	2,162.00	152,301.18	15,177.93	11.1%
5,200	7,000	75%	3,832,500	170,529.88	189,518.88	1,352.87	2,748.55	193,620.30	23,090.42	13.5%

E-35 Average Energy On-Peak: 34%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-35 - Primary

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					Components of Proposed Bill				Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC (D) x $0.000353	Franchise [(F) + (G)] x 0.0144	Monthly Bill under Proposed Rates (F) + (G) + (H)	Amount ($) (I) - (E)	% (J) / (E)
2,500	3,000	20%	438,000	46,528.70	43,398.62	154.61	627.17	44,180.40	(2,348.30)	-5.0%
2,500	3,000	30%	657,000	52,255.55	50,304.04	231.92	727.72	51,263.68	(991.87)	-1.9%
2,500	3,000	40%	876,000	57,982.40	57,209.46	309.23	828.27	58,346.96	364.56	0.6%
2,500	3,000	50%	1,095,000	63,709.25	64,114.88	386.54	928.82	65,430.24	1,720.99	2.7%
2,500	3,000	75%	1,642,500	78,026.38	81,378.43	579.80	1,180.20	83,138.43	5,112.05	6.6%
2,900	3,500	20%	511,000	53,657.65	50,420.43	180.38	728.65	51,329.46	(2,328.19)	-4.3%
2,900	3,500	30%	766,500	60,338.98	58,476.75	270.57	845.96	59,593.28	(745.70)	-1.2%
2,900	3,500	40%	1,022,000	67,020.30	66,533.08	360.77	963.27	67,857.12	836.82	1.2%
2,900	3,500	50%	1,277,500	73,701.63	74,589.40	450.96	1,080.58	76,120.94	2,419.31	3.3%
2,900	3,500	75%	1,916,250	90,404.94	94,730.21	676.44	1,373.86	96,780.51	6,375.57	7.1%
3,300	4,000	20%	584,000	60,786.60	57,442.23	206.15	830.14	58,478.52	(2,308.08)	-3.8%
3,300	4,000	30%	876,000	68,422.40	66,649.46	309.23	964.21	67,922.90	(499.50)	-0.7%
3,300	4,000	40%	1,168,000	76,058.20	75,856.69	412.30	1,098.27	77,367.26	1,309.06	1.7%
3,300	4,000	50%	1,460,000	83,694.00	85,063.92	515.38	1,232.34	86,811.64	3,117.64	3.7%
3,300	4,000	75%	2,190,000	102,783.50	108,081.98	773.07	1,567.51	110,422.56	7,639.06	7.4%
3,500	4,500	20%	657,000	65,305.55	62,104.04	231.92	897.64	63,233.60	(2,071.95)	-3.2%
3,500	4,500	30%	985,500	73,895.83	72,462.17	347.88	1,048.46	73,858.51	(37.32)	-0.1%
3,500	4,500	40%	1,314,000	82,486.10	82,820.30	463.84	1,199.29	84,483.43	1,997.33	2.4%
3,500	4,500	50%	1,642,500	91,076.38	93,178.43	579.80	1,350.12	95,108.35	4,031.97	4.4%
3,500	4,500	75%	2,463,750	112,552.06	119,073.76	869.70	1,727.19	121,670.65	9,118.59	8.1%
4,000	5,000	20%	730,000	73,739.50	70,305.85	257.69	1,016.11	71,579.65	(2,159.85)	-2.9%
4,000	5,000	30%	1,095,000	83,284.25	81,814.88	386.54	1,183.70	83,385.12	100.87	0.1%
4,000	5,000	40%	1,460,000	92,829.00	93,323.92	515.38	1,351.29	95,190.59	2,361.59	2.5%
4,000	5,000	50%	1,825,000	102,373.75	104,832.95	644.23	1,518.87	106,996.05	4,622.30	4.5%
4,000	5,000	75%	2,737,500	126,235.63	133,605.54	966.34	1,937.84	136,509.72	10,274.09	8.1%
4,500	6,000	20%	876,000	84,082.40	80,809.46	309.23	1,168.11	82,286.80	(1,795.60)	-2.1%
4,500	6,000	30%	1,314,000	95,536.10	94,620.30	463.84	1,369.21	96,453.35	917.25	1.0%
4,500	6,000	40%	1,752,000	106,989.80	108,431.14	618.46	1,570.31	110,619.91	3,630.11	3.4%
4,500	6,000	50%	2,190,000	118,443.50	122,241.98	773.07	1,771.42	124,786.47	6,342.97	5.4%
4,500	6,000	75%	3,285,000	147,077.75	156,769.09	1,159.61	2,274.17	160,202.87	13,125.12	8.9%
5,200	7,000	20%	1,022,000	97,035.30	93,673.08	360.77	1,354.09	95,387.94	(1,647.36)	-1.7%
5,200	7,000	30%	1,533,000	110,397.95	109,785.72	541.15	1,588.71	111,915.58	1,517.63	1.4%
5,200	7,000	40%	2,044,000	123,760.60	125,898.37	721.53	1,823.33	128,443.23	4,682.63	3.8%
5,200	7,000	50%	2,555,000	137,123.25	142,011.02	901.92	2,057.95	144,970.89	7,847.64	5.7%
5,200	7,000	75%	3,832,500	170,529.88	182,292.64	1,352.87	2,644.50	186,290.01	15,760.13	9.2%

E-35 Average Energy On-Peak: 34%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

Arizona Public Service Company

Typical General Service Bill Analysis
FEA Proposed: Rate E-35 - Transmission

Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
					Components of Proposed Bill				Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Base	CRCC	Franchise	Monthly Bill under Proposed Rates	Amount ($)	%
						(D) x $0.000353	[(F) + (G)] x 0.0144	(F) + (G) + (H)	(I) - (E)	(J) / (E)
2,500	3,000	20%	438,000	46,528.70	38,983.50	154.61	563.59	39,701.70	(6,827.00)	-14.7%
2,500	3,000	30%	657,000	52,255.55	45,888.92	231.92	664.14	46,784.98	(5,470.57)	-10.5%
2,500	3,000	40%	876,000	57,982.40	52,794.34	309.23	764.69	53,868.26	(4,114.14)	-7.1%
2,500	3,000	50%	1,095,000	63,709.25	59,699.76	386.54	865.24	60,951.54	(2,757.71)	-4.3%
2,500	3,000	75%	1,642,500	78,026.38	76,963.31	579.80	1,116.62	78,659.73	633.35	0.8%
2,900	3,500	20%	511,000	53,657.65	45,205.31	180.38	653.55	46,039.24	(7,618.41)	-14.2%
2,900	3,500	30%	766,500	60,338.98	53,261.63	270.57	770.86	54,303.06	(6,035.92)	-10.0%
2,900	3,500	40%	1,022,000	67,020.30	61,317.96	360.77	888.17	62,566.90	(4,453.40)	-6.6%
2,900	3,500	50%	1,277,500	73,701.63	69,374.28	450.96	1,005.48	70,830.72	(2,870.91)	-3.9%
2,900	3,500	75%	1,916,250	90,404.94	89,515.09	676.44	1,298.76	91,490.29	1,085.35	1.2%
3,300	4,000	20%	584,000	60,786.60	51,427.11	206.15	743.52	52,376.78	(8,409.82)	-13.8%
3,300	4,000	30%	876,000	68,422.40	60,634.34	309.23	877.59	61,821.16	(6,601.24)	-9.6%
3,300	4,000	40%	1,168,000	76,058.20	69,841.57	412.30	1,011.66	71,265.53	(4,792.67)	-6.3%
3,300	4,000	50%	1,460,000	83,694.00	79,048.80	515.38	1,145.72	80,709.90	(2,984.10)	-3.6%
3,300	4,000	75%	2,190,000	102,783.50	102,066.86	773.07	1,480.89	104,320.82	1,537.32	1.5%
3,500	4,500	20%	657,000	65,305.55	55,688.92	231.92	805.26	56,726.10	(8,579.45)	-13.1%
3,500	4,500	30%	985,500	73,895.83	66,047.05	347.88	956.09	67,351.02	(6,544.81)	-8.9%
3,500	4,500	40%	1,314,000	82,486.10	76,405.18	463.84	1,106.91	77,975.93	(4,510.17)	-5.5%
3,500	4,500	50%	1,642,500	91,076.38	86,763.31	579.80	1,257.74	88,600.85	(2,475.53)	-2.7%
3,500	4,500	75%	2,463,750	112,552.06	112,658.64	869.70	1,634.81	115,163.15	2,611.09	2.3%
4,000	5,000	20%	730,000	73,739.50	62,890.73	257.69	909.34	64,057.76	(9,681.74)	-13.1%
4,000	5,000	30%	1,095,000	83,284.25	74,399.76	386.54	1,076.92	75,863.22	(7,421.03)	-8.9%
4,000	5,000	40%	1,460,000	92,829.00	85,908.80	515.38	1,244.51	87,668.69	(5,160.31)	-5.6%
4,000	5,000	50%	1,825,000	102,373.75	97,417.83	644.23	1,412.09	99,474.15	(2,899.60)	-2.8%
4,000	5,000	75%	2,737,500	126,235.63	126,190.42	966.34	1,831.06	128,987.82	2,752.19	2.2%
4,500	6,000	20%	876,000	84,082.40	72,394.34	309.23	1,046.93	73,750.50	(10,331.90)	-12.3%
4,500	6,000	30%	1,314,000	95,536.10	86,205.18	463.84	1,248.03	87,917.05	(7,619.05)	-8.0%
4,500	6,000	40%	1,752,000	106,989.80	100,016.02	618.46	1,449.14	102,083.62	(4,906.18)	-4.6%
4,500	6,000	50%	2,190,000	118,443.50	113,826.86	773.07	1,650.24	116,250.17	(2,193.33)	-1.9%
4,500	6,000	75%	3,285,000	147,077.75	148,353.97	1,159.61	2,153.00	151,666.58	4,588.83	3.1%
5,200	7,000	20%	1,022,000	97,035.30	83,857.96	360.77	1,212.75	85,431.48	(11,603.82)	-12.0%
5,200	7,000	30%	1,533,000	110,397.95	99,970.60	541.15	1,447.37	101,959.12	(8,438.83)	-7.6%
5,200	7,000	40%	2,044,000	123,760.60	116,083.25	721.53	1,681.99	118,486.77	(5,273.83)	-4.3%
5,200	7,000	50%	2,555,000	137,123.25	132,195.90	901.92	1,916.61	135,014.43	(2,108.82)	-1.5%
5,200	7,000	75%	3,832,500	170,529.88	172,477.52	1,352.87	2,503.16	176,333.55	5,803.67	3.4%

E-35 Average Energy On-Peak: 34%

NOTES:
1) Bills do not include EPS, Regulatory Assessment, or Tax charges.
2) Franchise dollars are shown as an average percentage of total revenue requirement.
3) Proposed CRCC is calculated in accordance with the proposed Plan for Administration as filed in ACC Docket No. E-01345A-02-0403.
4) Present Rates are rates effective 7/1/2003.

APPENDIX A

QUALIFICATIONS OF

DENNIS W. GOINS

DENNIS W. GOINS

PRESENT POSITION

Economic Consultant, Potomac Management Group, Alexandria, Virginia.

AREAS OF QUALIFICATION

- Competitive Market Analysis
- Costing and Pricing Energy-Related Goods and Services
- Utility Planning and Operations
- Litigation Analysis, Strategy Development, Expert Testimony

PREVIOUS POSITIONS

- Vice President, Hagler, Bailly & Company, Washington, DC.
- Principal, Resource Consulting Group, Inc., Cambridge, Massachusetts.
- Senior Associate, Resource Planning Associates, Inc., Cambridge, Massachusetts.
- Economist, North Carolina Utilities Commission, Raleigh, North Carolina.

EDUCATION

College	Major	Degree
Wake Forest University	Economics	BA
North Carolina State University	Economics	ME
North Carolina State University	Economics	PhD

RELEVANT EXPERIENCE

Dr. Goins specializes in pricing, planning, and market structure issues affecting firms that buy and sell products in electricity and natural gas markets. He has extensive experience in evaluating competitive market conditions, analyzing power and fuel market operations and transactions, developing product pricing strategies, setting rates for energy-related products and services, negotiating power supply and natural gas contracts for private and public entities, and forecasting power requirements and fuel prices. He has participated in more than 100 cases as an expert on competitive market issues, utility restructuring, power market planning and operations, utility mergers, rate design, cost of service, and management prudence before the Federal Energy Regulatory Commission, the General Accounting Office, the Circuit Court of Kanawha County, West Virginia, and regulatory commissions in Arkansas, Georgia, Illinois, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Texas, Utah, Vermont, Virginia, and the District of Columbia. He has also prepared an expert report on behalf of the United States regarding pricing and contract issues in a case before the United States Court of Federal Claims.

SELECTED PUBLICATIONS, REPORTS, AND SPEECHES

1997 *Electric Utility Restructuring in South Carolina: Resolving Stranded Cost Issues*, report submitted to the South Carolina Public Service Commission, prepared on behalf of Nucor Steel, Darlington, SC, June 30, 1997.

1997 *Electric Utility Restructuring in South Carolina: Supplemental Report Responding to Other Parties' Plans and Comments Regarding Stranded-Cost Issues,* report submitted to the South Carolina Public Service Commission, prepared on behalf of Nucor Steel, Darlington, SC, July 21, 1997.

1995 *Expert Report of Dr. Dennis W. Goins on Behalf of the United States*, prepared in *Gulf States Utilities Company v the United States*, before the United States Court of Federal Claims, Docket No. 91-1118C.

1993 "Interruptible Rates as Effective DSM Options," speech before the *Demand-Side Resources Collaborative Working Group*, Salt Lake City, Utah.

1993 "Retail Wheeling: The Real Debate Begins," speech before the *Power Transmission: Access, Pricing & Policy* conference sponsored by Infocast, Inc., Washington, DC.

1990 "Survival or Prosperity in Competitive Power Markets: What's a Firm to Do?" in *Proceedings: 1989 Utility Strategic Issues Forum - What Does the Future Hold for the Electricity Business?*, Electric Power Research Institute, Palo Alto, California.

1990 *Planning for Competition in Bulk Power Markets: Research and Development Needs*, Electric Power Research Institute, Palo Alto, California.

1990 *Year 2000 Power Supply Reliability Assessment: Southeastern Reliability Council (SERC) and Southwest Power Pool (SPP) Regions*, (with Exeter Associates, Inc.), ARC Professional Services Group, Rockville, Maryland.

1986 *A New Era in Bulk Power Interchange Markets: Key Planning Issues*, Electric Power Research Institute, Palo Alto, California.

1985 "Can Incentive Regulation Improve Utility Performance? The Inherent Danger of a Simple Answer," *Public Utilities Fortnightly*, Vol. 115 (No. 1), pp. 20-23.

1984 *Financing Conservation Resource Development Through a Regional Finance Corporation: Volume I, Evaluating Potential Financing Activities*, (with M. Fisher and M. Savitz), Bonneville Power Administration, Portland, Oregon.

1984 *Financing Conservation Resource Development Through a Regional Finance Corporation: Volume II, Evaluating Alternative Organizational Structures*, (with M. Fisher, M. Savitz, and J. Hoerster), Bonneville Power Administration, Portland, Oregon.

1984 *Electric Power Supply Analysis for United States Air Force Bases*, ORI, Inc., Rockville, Maryland.

1984 *Interfuel Competition and Structural Change in Industrial Fuel Markets: Implications for the Electric Utility Industry*, Electric Power Research Institute, Palo Alto, California.

1984 *Market Outlook for Methanol and Propane Fuels for Fuel Cell Power Plants*, (with T. Bleakley), Electric Power Research Institute, Palo Alto, California.

1983 *Meeting Future Electric Power Needs with Natural Gas*, (with H.R. Linden, B.A. Hedman, G.K. Oates, and T.L. Wilke), Gas Research Institute, Chicago, Illinois.

1983 *Mechanisms to Promote Improved Energy-Use Efficiency in Irrigated Agriculture*, (with M. Fisher and M. Savitz), Bonneville Power Administration, Portland, Oregon.

1983 *Evaluation of Energy Adjustment Clauses*, Public Service Electric and Gas Company, Newark, New Jersey.

1983 *Incentive Regulation in the Electric Utility Industry*, (with M. Fisher, J. Hass, R. Ehrenberg, and R. Smiley), Federal Energy Regulatory Commission, Washington, DC

1983 "Negotiating Purchased Power Agreements with PURPA Generators," speech before *New Electric Utility Technologies* conference sponsored by Oak Ridge National Laboratory, St. Michaels, Maryland.

1983 "Issues in the Negotiation of Purchased Power Agreements Between Utilities and Cogeneration and Small Power Production Facilities," in *Research Needs for Effective Integration of New Technologies into the Electric Utility*, (M.A. Kuliasha and T.W. Reddoch, editors), Oak Ridge National Laboratory, Oak Ridge, Tennessee.

1980 *Power Pooling: Issues and Approaches*, (with S. Bowden), Department of Energy, Washington, DC

PARTICIPATION IN REGULATORY, ADMINISTRATIVE, AND COURT PROCEEDINGS

1. Arizona Public Service Company, before the Arizona Corporation Commission, Docket No. E-01345A-03-0347 (2004), on behalf of the U.S. Air Force (Federal Executive Agencies), re retail cost allocation and rate design issues.
2. PacifiCorp, before the Utah Public Service Commission, Docket No. 03-2035-02 (2004), on behalf of the U.S. Air Force (United States Executive Agencies), re retail cost allocation and rate design issues.
3. Dominion Virginia Power, before the Virginia State Corporation Commission, Case No. PUE-2000-00285 (2003), on behalf of Chaparral (Virginia) Inc., re recovery of fuel costs.
4. Jersey Central Power & Light Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02080506, OAL Docket No. PUC-7894-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.
5. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, BPU Docket No. ER02050303, OAL Docket No. PUC-5744-02 (2002-2003), on behalf of New Jersey Commercial Users, re retail cost allocation and rate design issues.

6. South Carolina Electric & Gas Company, before the South Carolina Public Service Commission, Docket No. 2002-223-E (2002), on behalf of SMI Steel-SC, re retail cost allocation and rate design issues.

7. Montana Power Company, before the First Judicial District Court of Montana, *Great Falls Tribune et al. v. the Montana Public Service Commission*, Cause No. CDV2001-208 (2002), on behalf of a media consortium (*Great Falls Tribune*, *Billings Gazette*, *Montana Standard*, *Helena Independent Record*, *Missoulian*, Big Sky Publishing, Inc. dba *Bozeman Daily Chronicle*, the Montana Newspaper Association, *Miles City Star*, *Livingston Enterprise*, Yellowstone Public Radio, the Associated Press, Inc., and the Montana Broadcasters Association), re public disclosure of allegedly proprietary contract information.

8. Louisville Gas & Electric *et al.*, before the Kentucky Public Service Commission, Administrative Case No. 387 (2001), on behalf of Gallatin Steel Company, re adequacy of generation and transmission capacity in Kentucky.

9. PacifiCorp, before the Utah Public Service Commission, Docket No. 01-035-01 (2001), on behalf of Nucor Steel, re retail cost allocation and rate design issues.

10. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 23640/ SOAH Docket No. 473-01-1922 (2001), on behalf of Nucor Steel, re fuel cost recovery.

11. FPL Group *et al.*, before the Federal Energy Regulatory Commission, Docket No. EC01-33-000 (2001), on behalf of Arkansas Electric Cooperative Corporation, Inc., re merger-related market power issues.

12. Entergy Mississippi, Inc., *et al.*, before the Mississippi Public Service Commission, Docket No. 2000-UA-925 (2001), on behalf of Birmingham Steel-Mississippi, re appropriate regulatory conditions for merger approval.

13. TXU Electric Company, before the Public Utilities Commission of Texas, PUC Docket No. 22350/ SOAH Docket No. 473-00-1015 (2000), on behalf of Nucor Steel, re unbundled cost of service and rates.

14. PacifiCorp, before the Utah Public Service Commission, Docket No. 99-035-10 (2000), on behalf of Nucor Steel, re using system benefit charges to fund demand-side resource investments.

15. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-190-U (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re the development of competitive electric power markets in Arkansas.

16. Entergy Arkansas, Inc. *et al.*, before the Arkansas Public Service Commission, Docket No. 00-048-R (2000), on behalf of Nucor-Yamato Steel and Nucor Steel-Arkansas, re generic filing requirements and guidelines for market power analyses.

17. ScottishPower and PacifiCorp, before the Utah Public Service Commission, Docket No. 98-2035-04 (1999), on behalf of Nucor Steel, re merger conditions to protect the public interest.

18. Dominion Resources, Inc. and Consolidated Natural Gas Company, before the Virginia State Corporation Commission, Case No. PUA990020 (1999), on behalf of the City of Richmond, re market power and merger conditions to protect the public interest.

19. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 18465 (1998) on behalf of the Texas Commercial Customers, re excess earnings and stranded-cost recovery and mitigation.

20. PJM Interconnection, LLC, before the Federal Energy Regulatory Commission, Docket No. ER98-1384 (1998) on behalf of Wellsboro Electric Company, re pricing low-voltage distribution services.

21. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, re market power in relevant markets.

22. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070458 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

23. GPU Energy, before the New Jersey Board of Public Utilities, Docket No. EO97070459 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

24. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070461 (1997) on behalf of the New Jersey Commercial Users Group, re unbundled retail rates.

25. Public Service Electric and Gas Company, before the New Jersey Board of Public Utilities, Docket No. EO97070462 (1997) on behalf of the New Jersey Commercial Users Group, re stranded costs.

26. DQE, Inc. and Allegheny Power System, Inc., before the Federal Energy Regulatory Commission, Docket Nos. ER97-4050-000, ER97-4051-000, and EC97-46-000 (1997) on behalf of the Borough of Chambersburg, Allegheny Electric Cooperative, Inc., and Selected Municipalities, re market power in relevant markets.

27. CSW Power Marketing, Inc., before the Federal Energy Regulatory Commission, Docket No.ER97-1238-000 (1997) on behalf of the Transmission Dependent Utility Systems, re market power in relevant markets.

28. Central Hudson Gas & Electric Corporation *et al.*, before the New York Public Service Commission, Case Nos. 96-E-0891, 96-E-0897, 96-E-0898, 96-E-0900, 96-E-0909 (1997), on behalf of the Retail Council of New York, re stranded-cost recovery.

29. Central Hudson Gas & Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0909 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

30. Consolidated Edison Company of New York, Inc., supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0897 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.

31. New York State Electric & Gas Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0891 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
32. Rochester Gas and Electric Corporation, supplemental testimony, before the New York Public Service Commission, Case No. 96-E-0898 (1997) on behalf of the Retail Council of New York, re stranded-cost recovery.
33. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 15015 (1996), on behalf of Nucor Steel-Texas, re real-time electricity pricing.
34. Central Power and Light Company, before the Public Utility Commission of Texas, Docket No. 14965 (1996), on behalf of the Texas Retailers Association, re cost of service and rate design.
35. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 95-1076-E (1996), on behalf of Nucor Steel-Darlington, re integrated resource planning.
36. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13575 (1995), on behalf of Nucor Steel-Texas, re integrated resource planning, DSM options, and real-time pricing.
37. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Initial Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
38. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Reply Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
39. Arkansas Power & Light Company, *et al.*, Notice of Inquiry to Consider Section 111 of the Energy Policy Act of 1992, before the Arkansas Public Service Commission, Docket No. 94-342-4 (1995), Final Comments on behalf of Nucor-Yamato Steel Company, re integrated resource planning standards.
40. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 94-202-G (1995), on behalf of Nucor Steel, re integrated resource planning and rate caps.
41. Gulf States Utilities Company, before the United States Court of Federal Claims, *Gulf States Utilities Company v. the United States*, Docket No. 91-1118C (1994, 1995), on behalf of the United States, re electricity rate and contract dispute litigation.
42. American Electric Power Corporation, before the Federal Energy Regulatory Commission, Docket No. ER93-540-000 (1994), on behalf of DC Tie, Inc., re costing and pricing electricity transmission services.
43. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 13100 (1994), on behalf of Nucor Steel-Texas, re real-time electricity pricing.

44. Carolina Power & Light Company, *et al.*, Proposed Regulation Governing the Recovery of Fuel Costs by Electric Utilities, before the South Carolina Public Service Commission, Docket No. 93-238-E (1994), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

45. Southern Natural Gas Company, before the Federal Energy Regulatory Commission, Docket No. RP93-15-000 (1993-1995), on behalf of Nucor Steel-Darlington, re costing and pricing natural gas transportation services.

46. West Penn Power Company, *et al.*, v. State Tax Department of West Virginia, *et al.*, Civil Action No. 89-C-3056 (1993), before the Circuit Court of Kanawha County, West Virginia, on behalf of the West Virginia Department of Tax and Revenue, re electricity generation tax.

47. Carolina Power & Light Company, *et al.*, Proceeding Regarding Consideration of Certain Standards Pertaining to Wholesale Power Purchases Pursuant to Section 712 of the 1992 Energy Policy Act, before the South Carolina Public Service Commission, Docket No. 92-231-E (1993), on behalf of Nucor Steel-Darlington, re Section 712 regulations.

48. Mountain Fuel Supply Company, before the Public Service Commission of Utah, Docket No. 93-057-01 (1993), on behalf of Nucor Steel-Utah, re costing and pricing retail natural gas firm, interruptible, and transportation services.

49. Texas Utilities Electric Company, before the Public Utility Commission of Texas, Docket No. 11735 (1993), on behalf of the Texas Retailers Association, re retail cost-of-service and rate design.

50. Virginia Electric and Power Company, before the Virginia State Corporation Commission, Case No. PUE920041 (1993), on behalf of Philip Morris USA, re cost of service and retail rate design.

51. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 92-209-E (1992), on behalf of Nucor Steel-Darlington.

52. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Rate Design (1992), on behalf of the Department of Energy, Strategic Petroleum Reserve.

53. Georgia Power Company, before the Georgia Public Service Commission, Docket Nos. 4091-U and 4146-U (1992), on behalf of Amicalola Electric Membership Corporation.

54. PacifiCorp, Inc., before the Federal Energy Regulatory Commission, Docket No. EC88-2-007 (1992), on behalf of Nucor Steel-Utah.

55. South Carolina Pipeline Corporation, before the South Carolina Public Service Commission, Docket No. 90-452-G (1991), on behalf of Nucor Steel-Darlington.

56. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 91-4-E, 1991 Fall Hearing, on behalf of Nucor Steel-Darlington.

57. Sonat, Inc., and North Carolina Natural Gas Corporation, before the North Carolina Utilities Commission, Docket No. G-21, Sub 291 (1991), on behalf of Nucor Corporation, Inc.

58. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-91-001 (1991), on behalf of North Star Steel-Minnesota.

59. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase IV-Rate Design (1991), on behalf of the Department of Energy, Strategic Petroleum Reserve.

60. Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 9850 (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve.

61. General Services Administration, before the United States General Accounting Office, Contract Award Protest (1990), Solicitation No. GS-00P-AC87-91, Contract No. GS-00D-89-B5D-0032, on behalf of Satilla Rural Electric Membership Corporation, re cost of service and rate design.

62. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 90-4-E (1990 Fall Hearing), on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

63. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1990), on behalf of the Department of Energy, Strategic Petroleum Reserve, re cost of service and rate design.

64. Atlanta Gas Light Company, before the Georgia Public Service Commission, Docket No. 3923-U (1990), on behalf of Herbert G. Burris and Oglethorpe Power Corporation, re anticompetitive pricing schemes.

65. Ohio Edison Company, before the Public Utilities Commission, Case No. 89-1001-EL-AIR (1990), on behalf of North Star Steel-Ohio, re cost of service and rate design.

66. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Cost of Service/Revenue Spread (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

67. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E002/GR-89-865 (1989), on behalf of North Star Steel-Minnesota.

68. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-17282, Phase III-Rate Design (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

69. Utah Power & Light Company, before the Utah Public Service Commission, Case No. 89-039-10 (1989), on behalf of Nucor Steel-Utah and Vulcraft, a division of Nucor Steel.

70. Soyland Power Cooperative, Inc. v. Central Illinois Public Service Company, Docket No. EL89-30-000 (1989), before the Federal Energy Regulatory Commission, on behalf of Soyland Power Cooperative, Inc., re wholesale contract pricing provisions

71. Gulf States Utilities Company, before the Public Utility Commission of Texas, Docket No. 8702 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

72. Houston Lighting and Power Company, before the Public Utility Commission of Texas, Docket No. 8425 (1989), on behalf of the Department of Energy, Strategic Petroleum Reserve.

73. Northern Illinois Gas Company, before the Illinois Commerce Commission, Docket No. 88-0277 (1989), on behalf of the Coalition for Fair and Equitable Transportation, re retail gas transportation rates.

74. Carolina Power & Light Company, before the South Carolina Public Service Commission, Docket No. 79-7-E, 1988 Fall Hearing, on behalf of Nucor Steel-Darlington, re fuel-cost recovery.

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77. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GR-87-670 (1988), on behalf of the Metalcasters of Minnesota.

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94. Bangor Hydro-Electric Company, before the Maine Public Utilities Commission, Docket No. 80-108 (1981), on behalf of the Commission Staff.

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100. Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-100, Sub 32, on behalf of the Commission Staff.

101. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 203, on behalf of the Commission Staff.

102. Virginia Electric & Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 170, on behalf of the Commission Staff.

103. Southern Bell Telephone Company, before the North Carolina Utilities Commission, Docket No. P-5, Sub 48, on behalf of the Commission Staff.

104. Western Carolina Telephone Company, before the North Carolina Utilities Commission, Docket No. P-58, Sub 93, on behalf of the Commission Staff.

105. Natural Gas Ratemaking, before the North Carolina Utilities Commission, Docket No. G-100, Sub 29, on behalf of the Commission Staff.

106. General Telephone Company of the Southeast, before the North Carolina Utilities Commission, Docket No. P-19, Sub 163, on behalf of the Commission Staff.

107. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 264, on behalf of the Commission Staff.

108. Carolina Power and Light Company, before the North Carolina Utilities Commission, Docket No. E-2, Sub 297, on behalf of the Commission Staff.

109. Duke Power Company, *et al.*, Investigation of Peak-Load Pricing, before the North Carolina Utilities Commission, Docket No. E-100, Sub 21, on behalf of the Commission Staff.

110. Investigation of Intrastate Long Distance Rates, before the North Carolina Utilities Commission, Docket No. P-100, Sub 45, on behalf of the Commission Staff.